COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Notice of Inquiry Use of Distributed Generation	)	D.T.E. 02-38

COMMENTS OF NSTAR ELECTRIC IN RESPONSE TO THE NOTICE OF INQUIRY REGARDING DISTRIBUTED GENERATION

I. INTRODUCTION

NSTAR Electric[1] hereby submits comments in response to the Notice of Inquiry (the "NOI") issued by the Department of Telecommunications and Energy (the "Department") on June 13, 2002, regarding the technical, economic and regulatory issues relating to the installation and use of distributed generation.

Over the past five years, NSTAR Electric (or the "Company") has devoted substantial resources to the evaluation of distributed generation technologies and to related issues involved in the installation and use of these technologies within the NSTAR Electric distribution system. These efforts have led the Company to conclude that there is long-term potential for distributed generation to play a role in demand-side management, demand response and distribution-system support.

Along with the long-term potential of distributed generation, however, there are significant challenges that NSTAR Electric and its customers face in relation to the installation of cost-effective distributed-generation technologies, especially in terms of

[1] NSTAR Electric is composed of Boston Edison Company, Commonwealth Electric Company and Cambridge Electric Light Company.

safe interconnection with the electric system. These comments are intended to provide the Department with a critical analysis of both the long-term potential and challenges of distributed generation as a resource option for the Company and its customers. Accordingly, these comments first discuss the development of a policy framework for the Department's facilitation of distributed generation. Second, these comments describe the key characteristics that must be considered in evaluating distributed generation, including size, technology and economics. Third, these comments identify and discuss the three areas within which Department action will be critical. Lastly, these comments provide a response to the Department's specific questions set forth in the NOI.

II. DEVELOPMENT OF A POLICY FRAMEWORK TO FACILITATE THE USE OF DISTRIBUTED GENERATION

Distributed generation is not a new idea, nor are there significant "unknowns" with respect to the issues that are involved in the interconnection of distributed-generation facilities to the electric distribution system. The current technologies, although subject to continual re-engineering and improvement, are generally well-recognized. A variety of these technologies have been in place on the NSTAR Electric system for many years and there are a number of customers who have recognized (and realized) the potential benefits of using distributed generation as a primary energy supply or as a back-up generation source. Yet, as the Department has correctly identified, there is mounting interest in the development of a regulatory approach to the use of distributed generation, which is providing the impetus for this proceeding. Therefore, it is important that the root of this impetus be understood in developing a regulatory response.

In NSTAR Electric's view, the root of this impetus reflects a concern that, collectively, the industry may be missing opportunities in the area of distributed generation because of organizational or structural issues. That is, customer-installed distributed generation applications have an impact not only on the customers that choose to use such technologies, but also on the local electric distribution utility and the customers that it continues to serve. In dealing with these impacts, barriers may be created that preclude the use of distributed generation in circumstances where it would otherwise be feasible. For example, a customer considering distributed generation may see benefits from energy savings, reliability, and power quality. In turn, the installation of distributed generation on that customer's site may or may not produce a benefit to the system, once all of the safety and reliability issues are resolved. However, utilities and customers have different needs and perspectives in relation to the planning process, and therefore, it is difficult to create a framework in which the customer can accommodate key utility planning criteria and objectives. Moreover, it is difficult for the customer to design its project to provide the specific benefit to the system that would be required in order for the customer's equipment to substitute for distribution-system investment. As a result, there is a sense that there may be missed opportunities in the area of distributed generation because of the way utilities and customers interact and undertake facility planning.

This concern has been heightened in recent years because of the increased interest in the use of distributed generation as a result of the emergence of a competitive market for electric generation, gains in the cost and performance of distributed generation technologies, the need to enhance system reliability and environmental concerns over emissions. These developments have reinforced the need to ensure that, in circumstances where distributed generation "makes sense," its promise is fulfilled and opportunities are not missed.

When viewed from this framework, it is clear that the Department's policy objective should not be to promote any particular type or level of investment in distributed generation technology. Rather, the policy should be to facilitate the complete and thorough evaluation and implementation of distributed generation projects by utilities and customers alike. As a technology, distributed generation is not inherently economic or uneconomic, or safe or unsafe. Like all technology, however, distributed generation should be viewed as a tool, rather than as goal in and of itself. When viewed as a tool, distributed generation has the potential to provide economic value to customers, either directly or through utilities, and therefore, the Department's policies should be aimed at assuring that the tool is properly used and that customer value is delivered. In that regard, the Department's primary focus in this docket should not be to favor or disfavor distributed generation, per se. The focus should be on identifying the actions that can be taken to ensure that the framework is in place to encourage the use of distributed generation where it will produce customer benefit.

In that respect, the Department's outlook should be similar to that which it adopted in connection with the promotion of competitive energy markets. There, the Department has stated that it will promote competition only where competition is able to sustain itself and that it will not attempt to create a competitive market, if the competitive market cannot develop and exist on its own or would artificially benefit only a narrow group of actors at the expense of others. The Department has also stated that its role is not to guarantee the success of entrants, but rather, to put in place the structural conditions necessary for an efficient competitive process.

At a policy level, therefore, the Department should have the following objectives in this proceeding: (1) to assure that there are no undue barriers to customer implementation of distributed generation; (2) to assure that distribution system reliability is not adversely affected; (3) to assure that customer and worker safety is protected; (4) to assure that costs and benefits of distributed generation are accurately reflected in rates and fairly allocated among customers.

In applying those objectives, it is necessary first to identify the relevant characteristics of distributed generation facilities, including the range of sizes, economics, technology types, operational impacts and safety issues. With that information developed, the Department will be in a position to identify the actions that can be taken to facilitate the cost-effective implementation of distributed generation. In that regard, there are three key areas for Department action, which are (1) the identification of policy guidelines on the use and ownership of distributed generation by electric utilities; (2) the development of uniform interconnection standards; and (3) the establishment of fair and reasonable standby rates. Action in these three areas will address integration issues between utilities and customers and permit even-handed evaluation and installation of beneficial distributed generation facilities.

III. SETTING THE STAGE: DEFINING DISTRIBUTED GENERATION

A. Size and Technology

A key factor in considering the interconnection of distributed generation technologies to the electric distribution "grid" is unit type and size. For example, there is a significant difference in connecting a 10 kilowatt ("kW") residential generating unit and a 2.5 megawatt ("MW") industrial generating unit, both with respect to safety and with respect to the impact that the interconnection of that unit will have on the system and its other customers. In that regard, type and size of the generating unit are the key factors in the complexity of safely interconnecting distributed generation technologies to a distribution system. For this reason, the existing interconnection standards of each distribution company outline the technical requirements to accommodate the various distributed-generation technologies. Similarly, the first step in devising a rational and forward-looking policy to encourage distributed generation as a resource option should be to define what is meant by "distributed generation" for the purposes of this proceeding.

Although there is a broad range of technologies that would qualify as "distributed generation," there are several technologies that are generally recognized within the industry at present. These technologies include both renewable and non-renewable forms of generation. Of these technologies, three technologies are well-established and commercially available, which are reciprocating internal combustion ("IC") engines, combustion turbines and microturbines. Reciprocating internal combustion engines are able to generate several MWs, but have traditionally dominated the market for small power generation (i.e., less than 1 MW). These engines can be fueled by diesel fuel, heavy oil, or natural gas. IC engines are characterized by relatively low initial start-up costs, proven reliability when maintained, good load-following capabilities and heat recovery potential. Reciprocating engines are useful for standby and peaking purposes, as well as commercial and industrial applications of less than 5 MW.

Combustion turbines are also a well-established technology that can range from several hundred kWs to hundreds of megawatts. Combustion turbines are used in power utility and industrial applications producing high-quality heat that can be used to generate steam for additional power generation (which is referred to as "combined cycle") or for heating or process loads. These turbines are fueled by natural gas or by petroleum-based fuels, or may even have dual-fuel capability. Since maintenance costs are relatively low for combustion turbines, this technology is generally used for industrial and commercial applications larger than 5 MW.

Microturbines or turbogenerators are very small combustion turbines with outputs of approximately 30 kW to 200 kW, however individual units may be used in combination to serve larger loads. Microturbines will have the capability to operate using a variety of fuels and are sized for commercial buildings or light industrial markets for limited cogeneration or power-only applications.

Fuel cells generate electricity by chemically reacting air and a fuel, without the use of combustion. Fuel-cell technologies are distinguished by the type of electrolyte and fuel used to create the necessary chemical reactions. Fuel cells produce direct current ("DC") that must flow through an inverter (generally incorporated into the fuel cell) to produce alternating current ("AC"), consistent with the operation of the distribution system. The largest fuel cell technology currently available is capable of providing up to 200 kW, however most fuel cells produce at a low voltage (i.e., 480 V) in comparison to a distribution substation (i.e., 4 kV, 13.8 kV or 24 kV on the NSTAR Electric system). Therefore, in those cases where power generated by a fuel cell would be fed into the electric system, additional equipment is required to raise the voltage level to a level that meets the requirements of the system. For this reason, fuel-cell technologies are generally used only to meet customer-specific loads.

All types of fuel-cell technologies are considered to be relatively quiet and clean from an environmental perspective. Given the relatively high cost of this technology at present, fuel cells are most likely to be cost-justified in areas where there are environmental concerns or customer-specific power-quality concerns.

Like fuel cells, photovoltaic systems produce DC power that must flow through an inverter to produce AC power. Photovoltaic ("PV") systems convert sunlight into electricity, and therefore, must be sited so as to capture sunlight on a regular basis. Most PV systems have outputs less than 75 kW. Although the costs associated with this technology are relatively much greater than other technologies, the use of PV systems may be appropriate where strong environmental concerns exist.

For the purpose of interconnecting with the system, these technologies are viewed by functional type, i.e., as inverters, induction generators or synchronous generators, with each type requiring a distinct level of safety protection in connecting with the grid. Static power converters or "inverters" are devices that allow distributed generation technologies that produce DC power (e.g., fuel cells and PV systems) to be connected to systems requiring AC power, such as the electric distribution system. Generally, inverters have the protective functionality to disconnect in response to contingencies on the distribution system, such as a short circuit. In addition, any generation technology that requires the use of an inverter is generally not self-sustaining, and therefore, interconnection with the electric system is more straightforward.

Induction generators are rotating electromechanical generators that generate power at a voltage and frequency as determined by the distribution system, and therefore, are generally not sustainable without some level of reliance on the distribution system. Because induction generators may be self-sustaining, if even for a short-period of time, there is more risk involved in connecting this equipment to the electric system.

Generally, synchronous generators do not require connection to the distribution system in order to maintain consistent voltage and energy supply levels and are often entirely self-sustaining.[2] Because the voltage and energy supply levels of synchronous generators are self-determined and are not a function of the voltage and energy-supply level requirements of the grid, synchronous generators have the potential to cause extensive damage to facilities and personnel if connected to the grid without being "synchronized" to the system.

The size of distributed-generation equipment varies widely within each type of technology. In the Company's experience, generating equipment is used by customers to produce a range of approximately 30 kW to 15 MW. The Company's existing interconnection standards establish the technical requirements for generating units up to 2.5 MW and a formal interconnection study is required for units in excess of 2.5 MW.[3] Proceedings in Texas and California have resulted in the development of policies governing generating units of up to 10 MW, while proceedings in New York have been

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2 Not all types of "synchronous generators" are considered to be "distributed generation." For example, commercially operated nuclear and fossil generating facilities employ the use of synchronous generating equipment.

3 The ISO-NE, Inc. requires a formal interconnection study to install a generating unit of 5 MW or greater.

confined to consideration of generating units of 300 kVA or less operating in parallel with radial distribution systems.[4]

The issue of size and type is also noted below in Section IV.B, in the context of safety requirements and interconnection standards. As discussed therein, the Company is currently engaged in a joint effort with other Massachusetts electric distribution companies to develop standardized interconnection requirements, which is likely to include size and type parameters. The Company anticipates that this effort will result in a determination of size and type parameters for safe interconnection with the electric system, and therefore, the Company is not making a specific recommendation for generator size parameters in this proceeding. However, to the extent that the size or type of a generating unit makes a difference in relation to a given policy consideration discussed below, the Company will indicate that fact.

B. Economics

It is generally recognized that distributed generation has the long-term potential to play a role in supporting available capacity to meet base-load and peak-power demands, serving critical customer loads, providing emergency standby power, improving user power quality and providing low-cost total energy. The primary interest in distributed generation, however, is to provide customers with the opportunity to secure the lowest cost solution for meeting their particular energy needs. As a result, the emergence of a market for distributed-generation technologies must ultimately depend upon the success of the manufacturers of those technologies in meeting the price, performance and reliability demands of customers in the marketplace.

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4 Electric distribution systems are designed as a "radial" system, where power flows on a single path from the substation to the point of customer demand.

Distributed-generation technologies are currently available to serve a wide-range of customer loads including residential uses (i.e., up to 10 kW) and large-scale commercial and industrial process requirements, which are able to take advantage of the waste heat that is generated through the production process. Customers may desire to install distributed generation for a variety of reasons, and depending upon those reasons, may identify the "lowest-cost solution" as the lowest cost of the initial investment required to install the generator, the lowest production cost, or the lowest total life-cycle cost. In other cases, the "lowest cost" for the customer may be the cost that is involved after taking into account site-specific, environmental or other strategic factors. In general, distributed-generation technologies currently face a significant challenge because of the relatively higher capital costs (dollars per kW) and production costs (dollars per kW-hour) in comparison to the customer's total cost of receiving service from the electric distribution company. In addition, in comparison to distribution and transmission system components, which are characterized by a relatively long useful life (40 to 60 years), distributed generation technologies generally have a useful life of 10-20 years, which means that any investment made in the technology must be recovered over a much shorter time period.

In the Company's experience, customers who are in a position to capitalize on the presence of "waste heat" in their operations are more likely to investigate distributed generation as a resource option. In addition, customers who have critical load or stringent power-quality or environmental requirements may find distributed generation to provide a value, although distributed-generation facilities (like central-station facilities) can either be a detriment or a benefit with respect to power quality issues. In the vast majority of cases, the initial investment and ongoing production costs associated with distributed generation technologies preclude the use of distributed generation as a resource option for the sole purpose of lowering electric supply costs.

Currently on the combined NSTAR Electric system, there are approximately 50 customers who have installed distributed-generation equipment that produce in excess of 60 kW of electric output on a per-unit basis. The technologies employed by these customers include cogeneration equipment, fuel cells, PV power cells, windmills and steam and water turbines. In total, the Company has approximately 112 customers who have the capability to generate their own electricity. Of those, approximately 73 percent classify their equipment as an "emergency generator" and approximately 20 percent classify their equipment as a "routine operation generator."

IV. DISCUSSION AND RECOMMENDATIONS

As noted above, there are three key areas that should be focused on by the Department in identifying initiatives to encourage the use of distributed generation, which are (1) the identification of policy guidelines on the use and ownership of distributed generation by electric utilities; (2) the development of uniform interconnection standards for electric distribution companies in the Commonwealth; and (3) the establishment of cost-based standby rates. Action in these three areas will address the integration issues between utilities and customers seeking to use distributed generation technologies, while creating an even playing field for the beneficial use of such facilities.

A. Utility Ownership

Distributed generation can be installed and owned either by a customer or by the electric utility. The most common arrangement with respect to distributed generation is that in which the facilities are installed and owned by the customer.[5] However, distributed generation may also be used by an electric utility to effectively reduce the load to be served by the distribution system. Accordingly, in planning its distribution system, a utility can view distributed generation as a potential alternative to expansion or reinforcement of its distribution facilities in a given location. To the extent that the installation and operation of distributed generation is determined to be less costly than the distribution investments that would otherwise be required, a utility could plan to install and own distributed generation in order to carry out its utility distribution function.

However, determining whether such a course of action is cost effective may raise a complex set of planning and financial issues for the utility. A comparison of distribution-system upgrades and distributed generation requires a comprehensive analysis because of the very different characteristics of each alternative. For example, there are differences that must be accounted for in relation to the useful lives of the equipment, the operating and maintenance profiles, and the reliability impacts on the system. Maintaining distributed generation capability will also have an impact on training, and operations and maintenance practices that must be considered. In addition, comparing these two alternatives requires the utility to assess the energy value of the distributed generation over time, which is a variable that does not exist with regard to typical transmission and distribution-system investment.

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5 The factors that must be considered in relation to customer-owned generation are addressed in other sections of these comments.

These considerations, however, do not raise new issues to be resolved in this proceeding. Although the analysis may be complex, these are the types of planning evaluations that utilities typically undertake. NSTAR Electric currently incorporates distributed-generation alternatives into its planning process where there is a potential for such technologies to represent a cost-effective alternative to distribution system investment.

Utility ownership of distributed generation does raise policy issues for the Department in connection with the framework of industry restructuring. A central objective of the Electric Restructuring Act of 1997 (the "Act") was the creation of a competitive market structure in which customers have the ability to choose among competitive suppliers of generation services. The chosen means of developing a competitive market was to require utilities to divest their generation. The overall concept was that distribution and transmission functions would be separated from generation functions. Thus, utility ownership of distributed-generation facilities may present a potential inconsistency with the requirements of the law. However, the law appears to distinguish between utility ownership of generation for commercial, competitive purposes (which is not contemplated), and utility ownership of distributed generation for the purpose of enhancing the efficiency of its distribution system (which is contemplated). See G.L. c. 164, § 1; G.L. c. 40J, § 4E(f)(2). Therefore, it does not appear that there is a specific prohibition on the use and ownership of distributed generation by a utility.

From a practical perspective, it may be possible to structure utility ownership of distributed generation to be compatible with the development of the competitive market. For example, it is plausible to assume that a utility that owned distributed generation solely for the purpose of enhancing its distribution system would sell the output of those facilities into the spot market, and flow the proceeds back to its customers, with minimal impact on the competitive market. Moreover, the fact that the amount of such generation will be small for the foreseeable future (relative to the size of the market) suggests that there should not be a high level of concern over market impacts.

Because distributed generation technologies have the potential to provide system benefits in relation to planned system upgrades, the use of distributed generation by a utility could provide a benefit to distribution customers. Therefore, it would be appropriate for the Department to develop a policy endorsing the use and ownership of distributed generation by electric utilities where it can enhance system reliability in a cost-effective manner, and indicating that such usage and ownership to be consistent with the requirements of the Act.

B. Interconnection with the Distribution System

The most critical issue involved in the interconnection of distributed generation is the need to ensure the safety and reliability of the electric system. Although interconnection standards may add a layer of complexity to the interconnection process, these standards provide the sole guarantee that the safety, reliability and power quality of the electric system will be maintained for all customers as distributed-generation facilities are introduced to the system to serve the needs of particular customers. However, the lack of uniformity between utilities in relation to the technical requirements associated with the interconnection process represents an important factor in the development of a market for distributed generation. Therefore, chief among the considerations involved in the development of a policy on distributed generation is the need to establish interconnection standards that maintain the safety and reliability of the electric system, while avoiding the imposition of unreasonable or unduly burdensome requirements on customers and their equipment providers.

As is the case with any source of electricity, distributed-generation systems are potentially dangerous both to people and property. The industry has devoted significant resources to the effort to minimize the safety risks posed by the introduction of large and small generation systems operating in parallel with the grid at numerous locations. Although certain technologies can be operated in isolation from the electric system, most customer-owned distributed generation facilities expect or require interconnection with the system in order to meet supply needs that are unmet by the customer-owned facilities or as a back-up power resource.

As a result, one of the most important safety issues for customer-owned distributed-generation facilities is the need to protect against a condition referred to as "islanding." Islanding occurs where a portion of the utility system containing both customer loads and a generation source is isolated from the remainder of the grid such that the generating facility continues to supply power to a portion of the grid when the balance of the grid has been de-energized. If an outage occurs on the distribution system, and a customer-owned generator continues to supply power to a local area, an island is created that is beyond the control of the local utility. This can create dangerous conditions for both customers and utility employees in that any one coming into contact with a line that is energized when it is expected to be de-energized would be seriously harmed. In addition, the generator may be "feeding" a short circuit, which can cause a fire on the system.

Interconnection standards establish the technical requirements necessary to protect against the potential for "islanding" and other safety concerns. For example, utilities protect against islanding through the use of mechanical relays and transfer switches and other safety equipment that are designed to automatically isolate generating facilities from the grid. In addition, interconnection standards typically delineate other parameters necessary to ensure the reliability and stability of the system, including voltage support, VAR support, frequency limits, power factor and harmonics. Such requirements are effective and necessary, but may become cost prohibitive for individual customers, especially those operating smaller generating units.[6] Typical interconnection standards also include requirements for control and monitoring systems (including metering and communications protocols), data requirements, and certification and testing procedures.

As discussed below, the development of uniform interconnection standards that ensure the safe and reliable operation of the electric system and streamline and standardize the process for interconnection in Massachusetts will be a key factor in eliminating potential barriers that may exist in relation to distributed generation technologies.

6 At the same time, smaller generating units may require less protection because equipment is readily available that ensures a cessation in operation in the event of a system outage. For example, distributed-generation technologies that require inverters to connect to the grid typically require only minimal protections because such technologies do not continue to operate when the grid is experiencing an outage.

C. Cost Responsibility for Standby Service

1. Introduction

As noted at the outset, a prime objective for the Department is to assure that customers see the appropriate economic signal in relation to the installation of distributed generation facilities. Probably the most important economic signal a customer receives from the utility is the rate charged for electric service. Hence, the design of rates for distributed generation customers is a very important area of the Department's inquiry in this docket.

The first (and crucially important) step in rate design is to be clear on the objective. In NSTAR Electric's view, the objectives in this instance are: (1) to design rates that accurately reflect the costs and benefits imposed on the electric distribution system by a customer that has distributed generation facilities, and (2) to design rates that fairly allocate such costs and benefits among all customers. This means that if distributed generation produces demonstrated distribution system savings, those savings could be reflected in the customer's rate. Conversely, if distributed generation produces incremental system costs, those should also be reflected.

It is important to recognize that if these objectives are adopted (as NSTAR Electric recommends), then the Department should adopt rates that neither favor nor disfavor distributed generation, but rather are designed to reflect accurately the impact of distributed generation on the system. This is consistent with the overall policy framework that the Company is proposing, which is that the policy adopted by the Department should not advocate for a specific outcome with respect to the choice or use of distributed generation technologies. Rather, the Department's objective in rate design should be to ensure that all parties have the right incentives to choose the right tool, without prejudging what the correct level of usage is by "tipping the scales" toward one outcome or another.

In developing appropriate rates, it is also important to recognize that the electric service that customers, who have distributed generation facilities, require from their local distribution utility can vary considerably, and as a result the impact on the distribution system can likewise vary considerably. Such customers may rely on the local utility for service for varying amounts of their load, for varying lengths of time, and with varying degrees of notice. Such service is generically referred to as Standby Service, but it is more accurate to think of this service as a family of services, each of which should have its own applicable rate design. These rate issues are discussed below.

2. Overview

Standby Service is provided to customers who serve all or a portion of their native load by means of self-generation (i.e., behind the meter generation) and who interconnect in parallel with the local distribution system for the purpose of taking delivery of replacement power as needed at times when their self-generation is either totally or partially unavailable (e.g., not operational).[7] Although every distributed generation power site could provide its own redundant backup power, such facilities generally seek

[7] For distributed generation that is not built for self-generation purposes, but is intended primarily to produce electricity for sale to the competitive generation market, only relatively small levels of standby service is needed. Standby Service for such customers is generally limited to "station service", i.e., the electricity needed to power the administrative activities of the plant and the start up service when the generation is put back on line. Accordingly, the rates and terms for Standby Service are not likely to have a significant impact on the economics for distributed generation for these types of plants. Standby rates more directly affect the economics of a decision to install distributed generation for self-generation purposes, and therefore these comments focus on those types of applications. Another category of self-generation may be dispatchable load reduction that would operate in a peak load shaving manner. This type of self generation would require standby service similar to that of continuous use self-generation.

access to both the grid and their own internal source(s) of generation in order to optimize the combination. Standby Service is essentially an insurance policy purchased by a customer to be certain that a constant supply of power is available via the customer's local distribution utility.

Standby Service in Massachusetts historically reflected a bundled service, consisting of generation capacity and energy, as well as the transmission and distribution components necessary to deliver the electricity to the customer's premises. However, since the restructuring of the electric industry under the Act, electric distribution companies have unbundled their rates into distribution, transmission and generation services, and are now primarily responsible only for the transmission and distribution of electricity to retail customers. Electricity is now available and sold to customers in a competitive market, which is then delivered by the local electric utility based on tariffs designed to recover the costs of delivering the electricity to consumers. Customers choosing to purchase standby generation service from a local distribution company will generally be served by the competitive wholesale generation market under the company's generally applicable Default Service rates, based on the electricity actually consumed. Thus, the following comments address primarily the delivery (i.e., distribution and transmission) components of Standby Service.

As described below, Standby Service rates designed on the basis of costs incurred to serve customers, provide appropriate price signals that should not impose a barrier to the installation cost-effective distributed generation. Standby Service rates set above the cost to serve would unfairly discourage the deployment of distributed generation resources, and correspondingly, Standby Service rates set below the cost to serve would provide unfair subsidies from other customers and unfairly encourage the deployment of inefficient resources. In that context, NSTAR Electric herein describes the history of Standby Service rates in Massachusetts, outlines the principles that should be used to develop cost-based Standby Service rates and, as requested by the Department, summarizes some recent developments in other states with regard to the design of Standby Service rates.

3. History of Standby Rates in Massachusetts

In the past, Standby Service included three separate categories of service: Backup Service, Maintenance Service, and Supplemental Service. **Standby Service** refers to the actual replacement power provided by the local utility to replace self-generated power when the self-generation units are unexpectedly out of service.

Maintenance Service is intended to provide customers who have an alternative source of power with electric energy and capacity to replace energy and capacity ordinarily generated by the facilities that make up the customer's alternative source of power, when such facilities are withdrawn from service for scheduled maintenance. Maintenance Service is distinguishable from Standby Service because of the customer's ability to pre-plan a maintenance-related outage. Maintenance Service is typically available during off-peak months and its pricing reflects this timing.

Supplemental Service is intended to supplement the output of a customer's alternative source of power where the alternative source of power serves less than the customer's maximum electrical load. Customers who satisfy only a portion of their electrical requirements from an alternative source of power (e.g., distributed generation) require Supplemental Service. This service is often priced at the rate schedule that would be applicable based on the customer's total load requirement absent any consideration for self-generation.

Although it is not uncommon for these services to be provided on a bundled basis under a single rate schedule, these services are often offered to customers under separate tariffs to provide customers with the flexibility to choose the specific services that they would like to purchase at cost-based rates. See Cambridge Electric Light Company Standby Service, Rate SB-1 (13.8 kV), M.D.T.E. No. 796, Cambridge Electric Light Company, Rate MS-1 (13.8 kV), M.D.T.E. No. 797, Cambridge Electric Light Company, Supplemental Service Rate SS-1 (13.8 kV), M.D.T.E. No. 798.

Rate-design precedent for Standby Service in Massachusetts is in the formative stages. Cambridge Electric Light Company/MIT, D.P.U. 94-101/95-36, at 46-47 (1995). Before 1995, the Department approved a number of rates for standby, maintenance and supplemental service for different electric utilities, which resulted in rates that varied from company to company. Eastern Edison Company, D.P.U. 92-148, at 36-37 (1992); Boston Edison Company, D.P.U. 92-92, at 58-63 (1992); Western Massachusetts Electric Company, D.P.U. 91-120, at 70-71 (1992); Western Massachusetts Electric Company, D.P.U. 90-300, at 82-87 (1991); Western Massachusetts Electric Company, D.P.U. 89-255, at 147 (1990); Nantucket Electric Company, D.P.U. 88-161/168, at 226-227 (1989). The Department acknowledged the absence of consistent precedent in Cambridge Electric Light Company/MIT, D.P.U. 94-101/95-36, at 46-47 (1995), where the Department stated:

> The Department has previously approved rates for standby and maintenance service for various companies on a case-by-case basis. However, the specific structure of the rates varied from company to company. See Eastern Edison

> Company, D.P.U. 92-148 (1992); Boston Edison Company, D.P.U. 92-92; Western Massachusetts Electric Company, D.P.U. 91-290 (1992); Nantucket Electric Company, D.P.U. 88-161/168 (1989). A review of the Department-approved standby, maintenance and supplemental rates indicates that the Department has not adopted a single method for the design of these rates, some of which were the result of settlement proposals approved by the Department. See Id. As such, there is no established Department precedent in this area.

Id. (emphasis added).

Currently, Standby Service in Massachusetts is provided under three general categories of rates: (1) the otherwise applicable rate schedule (or the generally available rate schedule applicable if the customer's total internal load were served by the utility without consideration of any self-generation) for usage delivered by the utility; (2) specially designed standby rates (e.g., Cambridge Electric Light Company – Rate SB-1, Rate MS-1 and Rate SS-1); and (3) special contracts (e.g., Commonwealth Electric Company - Southern Energy Canal Back-Up Service Agreement, Dartmouth Power Back-Up Service Agreement, Pilgrim Off-Site Power Agreement (currently under Department review)).

4. Guiding Principles for the Design of Standby Rates in the Restructured Market

The key principle applicable to the development of a well-designed standby service rate requires that it be a cost-based rate (i.e., designed to recover the full costs incurred to serve all Standby Service customers). This is a universally accepted tenet for rate design. All of the policy reasons for designing rates based upon cost causation apply to Standby Service (e.g., it prevents cross-subsidies and inappropriate revenue shifting, it provides appropriate economic price signal, and results in efficient use of societal resources). Once the appropriate costs are allocated to Standby Service, the rates should be designed so that costs that vary with a customer's usage are recovered on a variable charge basis, and costs that are fixed regardless of the customer's use are collected through fixed rate charges.

Standby Service is available instantaneously and requires that the local utility have adequate distribution capacity to serve this load at all times. The local utility must plan and design its distribution system to accommodate this standby load regardless of the frequency and level of usage actually recorded on the billing meter. As a result, distribution costs are fixed and do not vary with the amount of energy or demand consumption. Services and meter costs are customer-related and should be recovered through a monthly customer charge. The poles, conduit, conductor and line transformer portions of the distribution system are sized, generally, to meet the aggregate individual customer maximum load requirement. This is particularly the case for radial distribution systems. Since these costs are incurred to satisfy customers' individual maximum loads, these costs should be recovered through individual customer contract demands reflecting such loads.

The application of these rate-design principles to the design of a reasonable Standby Service rate suggests the use of the following three component charges: (1) an Administrative Charge; (2) a Customer Charge; (3) a Distribution and Transmission Contract Capacity Charge; and, if applicable, (4) a Generation Charge. Each of these charges is included to reflect all of the cost components, fixed and variable, necessary to provide Standby Service.

The **Administrative Charge** is designed to recover the additional costs incurred by the local electric utility in the administration of a customer's account on the Standby Service rate. An Administrative Charge is necessary for these services because there will be costs incurred to administer these rates properly that are in addition to the ordinary customer costs associated with a company's generally applicable distribution rates. For example, the determination of the billing quantities under the Standby Service Rate require additional meter readings, interval data monitoring and translation, and billing determinant calculations.

The **Customer Charge** is designed to recover the fixed costs associated with providing traditional customer-related services to a customer (i.e., those costs that do not vary depending on the amount of electricity consumed by the customer), such as the monthly billing and metering of each customer's electricity use. This should equal the generally applicable rate for the class.

The **Distribution and Transmission Contract Capacity Charge** is a monthly per kW or kVa charge assessed on each demand unit for which the customer requests Standby Service. It is appropriate to assess a Distribution and Transmission Contract Capacity Charge based on the contract level of Standby Service requested by a customer because it is necessary to maintain distribution system and transmission investments to serve that customer's maximum requested backup demand regardless of the actual level of the customer's backup load from time to time.

The design of the Distribution and Transmission Contract Capacity Charge reflects an underlying recognition that it is necessary to make a certain level of investment in local distribution and transmission in order to serve a customer's maximum requested backup load in any particular month. To assess the Distribution and Transmission Contract Capacity Charge on any basis other that the level of Standby Service requested by a customer would result in an under-recovery of the cost of serving Standby Service customers because these costs are incurred by the local electric utility whether or not a Standby Service customer actually receives electricity under a Standby Service rate. The Department has previously approved a distribution charge assessed on a contract demand basis in Boston Edison Company, D.P.U. 92-92, at 58-63 (1992).

In Cambridge Electric Light Company, D.P.U. 94-101/95-36, at 50-52 (1995), the Department declined to approve a similar component to Cambridge Electric Light Company's proposed Standby Service, concluding that assessing such a charge based on a customer's contracted demand, as opposed to actual demand, constitutes a demand ratchet. The Department stated that demand ratchets had been found to be inappropriate in the past because they distort incentives to conserve and could unfairly impose higher costs on certain customers. Id. at 50 (citations omitted). Although electric-use demand ratchets may affect a customer's incentive to conserve its demand for electricity, a customer's incentive to "conserve" Standby Service is unaffected. The amount of distribution assets to be in place in order to provide the contracted for Standby Service load cannot be reduced because a customer does not use Standby Service in a particular month. "Reducing consumption of electricity during off-peak periods in the short run does little or nothing to reduce the associated delivery system costs." Opinion and Order Approving Guidelines for the Design of Standby Service Rates, 99-E-1470 (Opinion 01-4) (the "New York Order"). In the context of Standby Service, a customer's actual monthly demand is not controlling, when seeking to establish a rate that recovers the fixed costs attributable to providing Standby Service. Accordingly, it is appropriate to assess a charge for distribution investment that is based on a customer's contracted for level of Standby Service, even if the customer's actual monthly demand for Standby Service is less than the customer's contracted for level of Standby Service.

5. Standby Rate Policies in Other States

On October 26, 2001, the New York Public Service Commission ("NYPSC") issued Guidelines for the Design of Standby Services Rates. As described by the NYPSC, the Guidelines recommend fundamental cost-based rate design principles that in most cases "avoid reliance on measurements of energy consumed (kwh) for charges for delivery service." Id. at 5. The Guidelines propose that distribution system delivery costs be recovered through a combination of the otherwise class-specific contract (fixed) demand charges and daily, as-used, on-peak demand charges. Id. at 7-8. Under the New York Guidelines, utilities would use the contract demand charge, to the extent possible, to recover the costs of "local" facilities, which are located closer to a customer's site and were put in place mostly to serve the individual customer. The Guidelines provide that these fixed, contract demand charges should apply to the customer's maximum annual demand. Id. at 8.

The Guidelines further propose that delivery system facilities located further from customer sites are considered "shared" facilities, and that costs associated with these shared facilities (the cost of which cannot be singularly attributed to individual customers) ought to be recovered through "as-used" demand charges. The as-used demand charge would apply only to the customer's daily maximum metered demand that occurs during the utility's delivery system peak periods.

In California, the Legislature has exempted most onsite generators going into operation in the next two years from standby charges for at least the next ten years. Order Instituting Rulemaking into Distributed Generation, *Interim Decision Adopting Standby Rate Design Policies*, 211 P.U.R.4th 280 (July 12, 2001) (the "California Order California Order"), citing Section 353.1(a) of the Public Utilities Code. The exceptions are diesel-fired generators and facilities with capacity in excess of 5 MW. In response to a state statutory mandate, the California Public Utilities Commission (the "CPUC") conducted a rulemaking to define rate design policies to apply to those facilities not included within the statutory exemption because of size, fuel choice, or date of initial operation.

The CPUC established the following four rate design policy goals for standby service:

1. Provide for fair cost allocation among customers
2. Allow the utility adequate cost recovery while minimizing costs to customers
3. Facilitate customer-side distributed generation deployment and
4. Send proper price signals to prospective purchasers of distributed generation.

Id. at 307. Applying these goals, the CPUC concluded that "most of the distribution system costs to serve standby customers appear to be fixed in nature." Id.

> For example, distribution system infrastructure investments are lumpy in nature. Traditional distribution system upgrades and extensions are generally installed in increments that provide system flexibility if growth exceeds projects, but could also risk over-building if load does not materialize. Typical increments of capacity needs are in the 1 MW range.

Id. (citations omitted). The CPUC distinguished between two different types of distribution infrastructure: (1) facilities-related costs that are fixed and independent of electricity use (e.g., poles and wires); and (2) peak demand-related (or capacity related) infrastructure costs that are more variable in nature (e.g., substation capacity and transformer costs). Id. at 307-308. However, the record before the CPUC was insufficient to determine specifically which costs are fixed and which are variable.

The CPUC noted that all participants in the rulemaking were in agreement that standby rate design should be cost based. Consistent with this view, the CPUC found that standby rates should be designed to appropriately reflect costs imposed on the utility system by all customers, "including those employing onsite generation." Id. at 310.

> [A] fixed standby reservation charge should be based only on facilities-related infrastructure costs that do not vary with usage. Standby customers with onsite generation who sign up for backup service should be charged a $/kW reservation charge for their reserved capacity. The reservation charge should reflect the distribution infrastructure costs that do not vary with usage. In addition, backup standby rates should include a volumetric rate, based on actual usage, that collects variable distribution costs, including peak demand-related costs.

Id. Thus, the CPUC concluded that generally applicable, longstanding rate-design principles were no less applicable to the design of new standby service rates. California electric utilities were directed to file proposed standby rates consistent with the CPUC's decision.

The CPUC concluded that, if a standby customer is willing to provide a "physical control" to remove load if its distributed generation unit is not operating, the utility does not need to build distribution infrastructure to serve that customer, thus avoiding fixed costs. If a customer is not willing to offer such physical assurance, the utility must construct infrastructure or continue to operate existing facilities to ensure that load from a customer taking on-demand backup service can be served. In such a case, the CPUC found that "it is appropriate for those costs to be recovered from backup customers." Id. at 308.

According to the Public Utility Commission of Texas ("TPUC"), the primary principles to be considered in the design of transmission and distribution rates are cost causation, simplicity, and equity to customers within the given rate classes. Re West Texas Utilities Company, P.U.C. Docket No. 22354, at 18 (October 24, 2001). However, to date, the TPUC has not developed separate standby rates for distributed generation customers, and has instead relied upon standard distribution rates for full service customers. The TPUC approved the use of demand ratchets in the design of standard distribution rates, finding that the use of ratchets "stabilize utility revenues and are an effective method to recover fixed distribution infrastructure costs." Id. at 19. "The Commission finds arguments that ratchets are not cost-justified or place an excessive burden on low load factor customers to be unpersuasive." Id.

V. RESPONSE TO DEPARTMENT'S QUESTIONS

(1) Refer to current distribution company interconnection standards and procedures in Massachusetts. Do these standards and procedures act as a barrier to the installation of distributed generation? If so, please describe.

a. If the current standards and procedures act as barriers to the installation of distribution generation, please describe what steps the Department should take to remove these barriers. As part of this response, please discuss whether the Department should establish uniform technical interconnection standards and procedures for distributed generation.

b. Please comment on whether the Department should adopt the IEEE's uniform technical interconnection standards, or the uniform standards adopted by other states, for use in Massachusetts.

As discussed above in section IV.B, the establishment of uniform interconnection standards for the Massachusetts electric distribution companies would be a critical step in facilitating the use of distributed generation within the Commonwealth. Following the merger of the BEC Energy and Commonwealth Energy Systems companies, the Company developed a set of uniform interconnection standards for the NSTAR Electric system. These standards serve as the existing interconnection standards on the NSTAR Electric system and are attached as Appendix A to these comments. To further the standardization effort, however, NSTAR Electric is currently working with other Massachusetts utilities to create a uniform set of interconnection requirements for the use of distributed generation in the Commonwealth.

The NSTAR Electric interconnection standards are designed to ensure that the introduction of distributed generation to the electric system will be accomplished without: (1) jeopardizing the safety of NSTAR Electric personnel or any member of the public; (2) causing harm or damage to the utility system or the equipment used to support that system; and (3) causing safety or power quality problems for other customers on the NSTAR Electric distribution system. These criteria are satisfied by the specification and the design/operation of the interface between the distributed generation facility and the Company's system. NSTAR Electric's technical specifications reference a number of IEEE guidelines as well as Underwriters Laboratory standards. In developing its interconnection standards, the Company has consulted with the IEEE and working group members who are associated with the "Standard for Distributed Resources Interconnected with Electric Power Systems." The new IEEE standard, P1547, currently under development, is being created by utility engineers and engineers from companies involved with all types of distribution generation products. The NSTAR Electric standard will be in compliance with the new IEEE standard P1547. In addition, although the Company's technical standards guide the interconnection process, NSTAR Electric typically performs a site-specific engineering evaluation depending on the type and size of the distributed generation and the characteristics of the distribution system at the point of interconnect.

Prior to the Department's NOI in this proceeding, NSTAR Electric had been working together with National Grid, Unitil and Western Massachusetts Electric Company to develop a uniform technical interconnection standard for Massachusetts operators of distributed generation. This effort is ongoing and the first milestone is to provide a consistent standard and easy to understand flow-chart process for all interconnects under 10 kW. The goal is to have this available to customers by October 1, 2002. Accordingly, the Company suggests that the Department encourage and monitor the continuation of that effort.

(2) Refer to current distribution company standby service tariffs. Do these tariffs act as a barrier to the installation of distributed generation? If so, please describe.

a. Please discuss the appropriate method for the calculation of standby or back-up rates associated with the installation of distributed generation. As part of this response, please discuss whether other states have established policies regarding back-up rates associated with distributed generation that may be appropriate for adoption in Massachusetts.

The Company's response to this question is presented above in Section IV.C. As stated therein, the primary objective for the Department in this proceeding should be to ensure that customers have the appropriate economic signal with respect to the installation of distributed generation facilities. Thus, the design of rates for distributed generation customers is a very important area of the Department's inquiry in this docket. In formulating an approach, the objectives should be: (1) to design rates that accurately reflect the costs and benefits imposed on the electric distribution system by a customer that has distributed generation facilities, and (2) to design rates that fairly allocate such costs and benefits among all customers. Principles of cost causation and the avoidance of cross-subsidies needs to be incorporated into the rate-design process in this area.

(3) Please discuss the role of distributed generation with respect to the provision of reliable, least-cost distribution service by the Massachusetts distribution companies.

a. What steps should the distribution companies take in order to identify areas where the installation of distribution generation would be a lower-cost alternative to system upgrades and additions?

b. What steps should the distribution companies take to encourage the installation of cost-effective distributed generation in their service territories?

c. What other issues are appropriate for consideration as part of the Department s investigation of distributed generation?

There are two categories of system planning issues that arise in consideration of distributed generation within an electric system. The first issue concerns utility-owned distributed generation, and whether the use of distributed generation technologies can serve as a substitute or complement to investment in distribution-system infrastructure that is needed to maintain reliability. With respect to customer-owned distributed generation, there are issues involved in incorporating those facilities into system-planning efforts, both from an engineering and load-supply perspective.

As is true with customer-owned generation, the threshold issue for utility-owned distributed generation is whether there are technologies that can be used in a given situation that represent a more cost-effective resource option than investment in the distribution system. As mentioned above, the life-cycle of distribution-system infrastructure upgrades tends to be significantly longer than the life-cycle of existing generation technologies, which diminishes the potential that distributed generation technologies will prove to be more cost-effective than infrastructure upgrades in the long run. In addition, distributed generation technologies do not tend to produce a level of output analogous to that achieved through infrastructure upgrades. This makes it unlikely that distributed generation will be comparable in assessing distribution-system investments for capacity purposes.

For example, distribution circuits are typically capable of carrying approximately 5-10 MW of power. Generally, distribution circuits can be fed from more than one source (i.e., from Transformer A or Transformer B, or Substation A or Substation B), which provides for the rerouting of power under system contingencies to meet customer demand. Distributed generation technologies tend to provide significantly less output than a distribution circuit and do not generally have built-in redundancy to ensure reliability in the event of an equipment outage. If the distribution system is designed to rely on the availability of supply from a customer-installed generation facility (i.e., the circuit is not replaced or upgraded because of the presence of distributed generation), the system will be unprepared to meet customer demands on the circuit in the event that the customer's facility is taken off line. Therefore, in calculating the investment required to upgrade the circuit versus the installation of a distributed generation technology, the reliability of the distributed generation technology will be an important factor.

With respect to the system-planning issues associated with customer-owned distributed generation, there are a number of factors that need to be considered. First, the Company is faced with a number of "unknowns" and uncertainties that make it difficult to incorporate and rely on load generated from small on-system producers and to ensure overall system reliability. For example, the NSTAR Electric distribution system is designed in part as a radial (single source) system and in part as a network system. The radial system is designed for power flow from the system to the customer.[8] The addition of distributed generation into the system, therefore, creates a number of engineering challenges, which will increase in direct proportion to the level and type of distributed generation introduced into the system. At the same time, to factor into the Company's

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[8] The City of Boston (and other areas of the distribution system) is designed as a "network" system. In a networked system, power is able to flow in multiple directions without constraint. Implementation of distributed generation in downtown Boston would require careful consideration and planning before distributed generation facilities could be introduced. In general, the redundancy in supply, the nature of the existing equipment used in maintaining the integrity of the network and the overall complexity of system coordination within the network structure creates a substantial reliability problem in accommodating parallel generation. In addition, these factors would make the interconnection process much more costly.

planning process, a meaningful level of generation must be available to offset the Company's load requirement.

Second, system reliance on customer-owned generation introduces a layer of complexity and cost not inherent in distribution-system investment in that the operation of the unit is placed somewhat beyond the Company's control. For example, for circuit replacements, the Company envisions that the placement of distributed generation at the location of the load (as opposed to the substation) could, in certain cases, be useful in relieving stress on the circuit. In that regard, the distribution company could solicit interested parties served on the circuit to consider placement of distributed generation in order to avoid or delay the circuit upgrade. Assuming that the cost of the technology would be less than the cost of the upgrade, and that the capabilities added to the system were comparable, the Company would have to consider the added costs associated with increased monitoring, relaying, switching, metering or other operational and infrastructure changes that might be required to accommodate such equipment. In addition, the Company would have to ensure: (1) that it could expect system benefits consistent with the useful life of the distributed generation assets; (2) that the unit would remain available in the event of bankruptcy, customer relocation, lack of interest or any other customer-specific determination to cease the arrangement; (3) that the unit is properly maintained in reasonable working order; and (4) that there is sufficient redundancy within the system to maintain reliability levels for customers. Where the equipment is owned by the customer, it will be difficult for the Company to maintain the level of control that will be necessary to rely upon such units to meet system requirements, unless sufficient protections can be put into place.

NSTAR Electric currently considers distributed generation as an option in its system-planning process in relation to substation upgrades. To date, the use of distributed generation technologies has not been demonstrated to be feasible or economical in comparison to traditional investment in substation infrastructure. However, the Company will continue to support the future development of distributed generation technologies and to assess whether there are benefits to be gained in its implementation.

VI. CONCLUSION

The Company appreciates the opportunity to comment on the important issues raised in this proceeding. NSTAR Electric recognizes that there is long-term potential for distributed generation to play a key role in demand-side management, demand response and distribution-system support. In devising a policy to encourage the use of distributed generation technologies, the Department must assess both the practical considerations and constraints. The Department must balance the desire to promote distributed generation technologies with the need to ensure the safety and reliability of the electric distribution-system. Lastly, the Department must consider customers who do not directly benefit from the use of distributed generation and ensure that they do not assume the costs of providing back-up service to those customers who do benefit. This evaluation and balancing of interests will enable the Department to establish a structural framework that facilitates the cost effective use of distributed generation for the benefit of customers without jeopardizing the safety and reliability of electric service in the Commonwealth.

TABLE OF CONTENTS